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Energy Resources Conservation and Development Commission

In the Matter of: APPLICATION FOR CERTIFICATION FOR THE HIDDEN HILLS SOLAR ELECTRIC GENERATING PROJECT	DOCKET NO. 11-AFC-02

CENTER FOR BIOLOGICAL DIVERSITY

OPENING TESTIMONY

TESTIMONY OF BILL POWERS, P.E.

EXHIBIT 536

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I. Introduction

My testimony addresses the failure of the Hidden Hills Solar Electric Generating System (HHSEGS) Final Staff Analysis (FSA) to evaluate a distributed generation solar photovoltaic (PV) alternative to the proposed project, and 2) that identifying the need for flexible capacity as a project objective is inappropriate, given the state has adequate flexible capacity for the foreseeable future, and 3) whatever flexible capacity is provided by the HHSEGS project is provided by its gas-fired steam boiler capacity, not the solar component of the project.
I am a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. I have permitted five 50 MW peaking turbine installations in California, as well as numerous gas turbine, microturbine, and engine cogeneration plants around the state. I organized conferences on permitting gas turbine power plants (2001) and dry cooling systems for power plants (2002) as chair of the San Diego Chapter of the Air & Waste Management Association. I am the author of March 2012 Bay Area Smart Energy 2020, a distributed energy strategic plan for the Bay Area that would reduce greenhouse gas emissions from electricity generation by 60 percent by 2020 using the zero net energy goals in the state's *Long-Term Energy Efficiency Strategic Plan* as a framework. I also wrote the October 2007 strategic energy plan for the San Diego region titled "San Diego Smart Energy 2020." The plan uses the state's Energy Action Plan as the framework for accelerated introduction of local renewable and cogeneration distributed resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. I am the author of several recent articles in Natural Gas & Electricity Journal on use of large-scale distributed solar PV in urban areas as a cost-effective substitute for new gas turbine peaking capacity.

II. FSA Correctly Lists the Virtues of a Solar PV Alternative to the Proposed Project

The FSA provides a partial list of advantages of solar PV over the proposed power tower, stating (p. 6.1-1):

> Staff concludes that the primary environmental benefits of the Solar Photovoltaic (PV) Alternative compared to the proposed project are greatly reduced impacts on Visual Resources, Biological Resources, and Cultural Resources. The Solar PV Alternative reduces the magnitude of potential impacts on Water Supply. The Solar PV Alternative would eliminate the potential for mortality and morbidity of avian species from exposureto concentrated solar flux over the solar collector arrays. Because the Solar PV Alternative would not involve installation of solar power towers or other extremely tall structures, the potential for avian species to collide with the types of equipment and permanent facilities that would be part of the proposed project would be reduced under the Solar PV Alternative. If substantially reducing the extent and severity of direct environmental effects is the priority, then the Solar PV Alternative would be environmentally superior to the proposed project. An analysis of the environmentally superior alternative comparing the effects of each of the project alternatives to the proposed HHSEGS project is at the end of this alternatives analysis.

The FSA does not mention an overwhelming virtue of solar PV from a CEQA perspective – that it can be located on rooftops and parking lots in urban and suburban areas to effectively eliminate impacts on land, fauna, and flora.

III. FSA Correctly Identifies Gap Between Existing DG PV Program Targets and 2020 DG PV Goal

The FSA correctly identifies a substantial gap between the expected amount of DG PV that will be built under existing programs and Governor Brown's target of 12,000 MW of DG PV by 2020, stating (FSA, 6.1-13 and 6.1-14):

> There is no single accepted definition of renewable DG. The *2011 Integrated Energy Policy Report* published by the Energy Commission provides this definition: "For the purposes of the 12,000 MWs of renewable distributed generation by 2020 goal, distributed generation is defined as: (1) fuels and technologies accepted as renewablefor purposes of the Renewables Portfolio
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> Standard; (2) sized up to 20 MWs; and (3) located within the low-voltage
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> distribution grid or supplying power directly to a consumer" (Energy Commission 2012c). As of 2011, a total of approximately 3,000 MWs of renewable DG capacity has been installed; another 6,200 MWs is pending or authorized under existing state programs that support DG.
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> If existing state programs to support DG, including solar PV, are fully successful, the state could add approximately 6,000 MWs of additional capacity in the next several years. Additional programs or incentives may be needed to attain the 2020 goal specified in the Governor's Clean Energy Jobs Plan (Energy Commission 2011b).

The assertion that DG PV is impractical as an alternative to the HHSEGS because "renewable DG projects alone would not supply enough electricity to meet the state's mandated RPS program goals" contradicts the FSA's statement that existing DG PV programs will fall far short of the state's 2020 target of 12,000 MW DG PV. The issue is not the practicality of relying exclusively on DG PV to reach the state's 2020 RPS target. The issue is over-procurement of large central station solar projects, like HHSEGS, and under-procurement of DG PV. This out-of-balance procurement pattern may assure that the goal of 12,000 MW of DG PV by 2020 is not met.

IV. FSA Is Contradictory in Identifying Superiority of Solar PV to Proposed Project, Identifying Need for More DG PV to Reach 12,000 MW Target, while Eliminating a DG PV Alternative from Consideration

The FSA states (p. 6.1-15 and p. 6.1-16), **"**The characteristics of the DG category of renewable energy generation make it an impracticable alternative in the context of a CEQA alternatives analysis. The following reasons are then offered to support the position that DG PV is impractical:

- *Lack of Defined Projects with Sites*
- *No Oversight or Permitting Authority for a DG PV Alternative*
- *Voluntary Participation in On-site Generation Programs*
- *Failure to Meet Critical Project Objectives* - renewable DG projects alone would not supply enough electricity to meet the state's mandated RPS program goals.

The stated reasons for the impracticality of DG PV might have some merit if they had not already been disproven in practice. For example, the *California Solar Initiative* (CSI) lacks defined projects with sites, there is no oversight or permitting authority, it relies on voluntary participation. Yet the CSI program is exceeding its project timeline to install approximately 1,800 MW of DG PV by 2016. None of the first three reasons offered in the FSA to justify the impracticality of a DG PV alternative have impeded the practically of the CSI program to methodically add DG PV at a pace that exceeds the CSI program timeline.

California's electric utilities are building DG PV projects on the same scale as 500 MW HHSEGS. SCE expressed confidence in its March 2008 application to the CPUC for its 500 MW urban PV project that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure, stating "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory"[1] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[2]

SCE stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[3] SCE explains:

> SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits.[4]

SCE also notes that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[5]

> The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions.

[1] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[2] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.
[3] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[4] Ibid, p. 9.
[5] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[6] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[7]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[8]

> This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program.

The use of the term "smaller scale" in the CPUC press release is a misnomer. Clearly a 500 MW distributed PV project is a scale as large as the 500 MW HHSEGS solar thermal project.

V. Distributed PV Is at the Top of the Energy Action Plan Loading Order and Integral to the Energy Efficiency Strategic Plan

1. 12,000 MW DG PV Target Will Not Be Met Without Pro-Active Effort

The FSA states, in discussing the conservation and demand-side management alternative to HHSEGS, that cost-effective energy efficiency is the resource of first choice in meeting California's energy needs consistent with the state's *Energy Action Plan* - EAP (p. 6.1-16):

> The EAP envisions a "loading order" of energy resources to guide agency decisions: (1) the agencies will optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand, (2) recognizing that new generation is necessary and desirable, the agencies intend to meet the need first by renewable energy resources and distributed generation, and (3) because the preferred resources require both sufficient

[6] Ibid, p. 6.

[7] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.

[8] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.

> investment and adequate time to "get to scale," the agencies will support additional clean, fossil-fueled, central station generation (Energy Commission and CPUC 2003).

Energy Action Plan I, Under "Optimize Energy Conservation and Resource Efficiency," states (p. 5) "Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

Energy Action Plan I identifies rooftop PV as a de facto energy efficiency measure with this statement. As noted in the HHSEGS (p. 6.1-16), energy efficiency is at the top of the loading order. Energy Action Plan I also states, Under "Promote Customer and Utility-Owned Distributed Generation," (p. 7):

> Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality. The state is promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system. Clean distributed generation should enhance the state's environmental goals. This determined and aggressive commitment to efficient, clean and renewable energy resources will provide vision and leadership to others seeking to enhance environmental quality and moderate energy sector impacts on climate change. Such resources, by their characteristics, are virtually guaranteed to serve California load. With proper inducements distributed generation will become economic.
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> - Promote clean, small generation resources located at load centers.
> - Determine system benefits of distributed generation and related costs.
> - Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program.

Energy Action Plan I prioritizes rooftop PV as the preferable renewable resource, but indicates obliquely that it is costly and that in any case distributed PV is not eligible to participate in the Renewable Portfolio Standard (RPS) program. Therefore investor-owned utilities have no incentive to develop distributed PV resources. Since *Energy Action Plan I* was approved in 2003, PV cost has dropped dramatically. Commercial distributed PV is half the cost it was in 2003 and costs continue to drop. Residential PV is following quickly behind. Distributed PV is also now eligible for the RPS program.[9]

Energy Action Plan II was adopted in September 2005.[10] The purpose of Energy Action Plan II is stated as (p. 1): "EAP II is intended to look forward to the actions needed in California over the next few years, and to refine and strengthen the foundation prepared by EAP I." Energy Action Plan II reaffirms the loading order stating (p. 2):

> EAP II continues the strong support for the loading order – endorsed by Governor

[9] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009. "The energy generated from the project will be used to serve Edison's retail customers and the output from these facilities will be counted towards Edison's RPS goals."

[10] Energy Action Plan II: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

> Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation.

The CEC's *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report* (December 2009), underscores the integration of building PV as a critical component of "net zero" energy use targets for new residential and commercial construction, under the heading "Energy Efficiency and the Environment," explaining:[11]

> With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.
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> A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year.

The HHSEGS FSA acknowledges the state's commitment to zero net energy residential and commercial buildings, stating (FSA, p. 6.1-17):

> The 2008 EAP update also discusses CPUC's strategic planning process to develop comprehensive, long-term strategies for making energy efficiency a way of life for Californians. CPUC adopted California's first *Long-Term Efficiency Strategic Plan* in 2008, which was developed through a collaborative process with CPUC's regulated utilities—PG&E, SCE, SDG&E, and Southern California Gas Company—and many other key stakeholders. The long-term plan provides a statewide roadmap to maximize achievement of cost-effective energy efficiency in California's electricity and natural gas sectors from 2009 through 2020 and beyond. CPUC's 2011 update to the *Energy Efficiency Strategic Plan* (CPUC 2011) is a comprehensive plan with goals and strategies covering all major economic sectors in the state.

Major goals of the *Long-Term Energy Efficiency Strategic Plan* include:

- All new residential construction will be zero net energy by 2020;
- All new commercial construction will be zero net energy by 2030;
- 25% of existing residential reaches near zero net energy by 2020;

[11] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 56.

- 75% of existing residential reduces electricity consumption by 30% by 2020;
- 100% of existing multifamily reduces electricity consumption by 40% by 2020;
- 50% of existing commercial reaches zero net energy by 2030;
- Central air conditioning loads will be reduced by 50% by 2020, 75% by 2030.

The electricity consumption reduction achieved by reaching the *Energy Efficiency Strategic Plan* goals for existing structures are shown in Table 1.

Table 1. California Energy Efficiency Strategic Plan Goals[12]

Category	2008 statewide demand[13] (GWh)	Targets	2020 reduction in demand (GWh)	2020 statewide demand if targets achieved (GWh)
Residential	91,493 Single family: 61,026 Multi-family: 30,467	2020: 25 percent of existing homes have 70 percent decrease in purchased electricity from 2008 levels, 75 percent of existing homes have a 30 percent decrease in purchased energy from 2008 levels, and 100 percent of existing multi-family homes have a 40 percent decrease in purchased energy from 2008 levels. 100 percent of new homes will be ZNE. [Approximately one-third of all households live in multi-family residences and two-thirds in single family homes.][14]	36,597	54,896
Commercial	106,569	2030: 50 percent of existing commercial buildings will be retrofit to ZNE through energy efficiency and the addition of clean rooftop PV. 100 percent of new commercial buildings reach ZNE in 2030. [It is assumed that 20 percent of existing commercial buildings reach ZNE by 2020 based on CPUC projections.]	21,314 (20 percent ZNE by 2020)	85,255
Industrial	44,142	2020: Energy intensity of industrial facilities will be reduced by 25 percent.	11,035	33,107
Agriculture	20,705	2020: Energy intensity of agricultural operations will be reduced by 15 percent.	3,106	17,599
Subtotal	262,909		72,052	190,857
Misc. loads[15]	~14,000		--	14,000

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[12] Ibid, p. 20, p. 30, p. 34, p. 41.
[13] CEC, *California Energy Demand 2010-2020 Adopted Forecast*, December 2009. Form 1.1 - Statewide California Energy Demand 2010-2020 Staff Revised Forecast Electricity Consumption by Sector (GWh), p. 37.
[14] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 9. See: http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf
[15] CEC, *California Electricity Demand 2010-2020 Commission-Adopted Forecast*, Forms 1.1 and 1.1c, December 2009. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html. The approximate 277,000 GWh (276,509 GWh) statewide total is from Form 1.1c. The category-specific 2008 residential, commercial, industrial, and agriculture demand is from Form 1.1 and sums to 262,909 GWh. The difference between total 2008 demand and residential, commercial, industrial, and agricultural demand, which represents other loads including mining, telecommunications, communications, and utilities (TCU), and street lighting, is about 14,000 GWh.

Total	~277,000		72,052	204,857
Net reduction in statewide utility-supplied consumption, 2008 to 2020:				~26 percent

Assuming that 30 percent of the reductions shown in Table 2 are achieved by energy efficiency measures alone, and that additional reductions are achieved by adding rooftop PV and/or parking lot PV at the structure, over 12,000 MW_{ac} of rooftop and/or parking lot PV that would need to be installed by 2020.[16]

The FSA is flawed in its failure to identify rooftop PV as a higher priority in the *Energy Action Plan* loading order, and California's *Energy Efficiency Strategy Plan*, than utility-scale remote solar resources like HHSEGS. Rooftop and parking lot distributed PV is an integral component of the long-term energy efficiency strategy plan adopted by the CPUC in 2008. *Energy Action Plan II* declares cost-effective energy efficiency as the resource of first choice for meeting California's energy needs. The CEC's failure to even consider DG PV as an alternative to the proposed HHSEGS solar thermal projects ignores the integral role of distributed PV in the CEC's own definition of energy efficiency and zero net energy buildings in the 2009 IEPR.

2. IOUs Need Only Provide a Basic Level of Existing Information on Individual IOU Substation Capacities to PV Developers to Interconnect Over 13,000 MW of Distributed PV with Minimal Interconnection Cost

The CPUC has also calculated, for the entire inventory of approximately 1,700 existing IOU substations, the amount of distributed PV that could be accommodated with minimal interconnection cost based on the following reasoning:[17]

> Rule 21 specifies maximum generator size relative to the peak load on the load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).
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> However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the

[16] 40 percent of residential reduction, for the 25 percent of homes reducing grid demand by 70 percent, is displacement by onsite PV = 15,256 GWh x 0.40 = 6,103 GWh per year. 70 percent of commercial reduction, for the ~20 percent of existing commercial buildings reducing grid demand by 100 percent by 2020, is displacement by onsite PV = 21,314 GWh x 0.70 = 14,920 GWh per year. 10 percent of multifamily reduction, for the 100 percent of existing multifamily reducing grid demand by 40 percent by 2020, is displacement by onsite PV = 30,467 GWh x 0.10 = 3,047 GWh per year. Total substation by onsite PV in 2020 = 6,103 GWh + 14,920 GWh + 3,047 GWh = 24,070 GWh. Assume fixed rooftop PV production = 1,900 kWh per kW_{ac} of installed PV capacity. Therefore, quantity of onsite PV necessary = (24,070 GWh/yr x 1,000,000 kWh/GWh)/(1,900 kWh/yr per kW_{ac}) = 12.7 x 10^6 kWh_{ac} (12,700 MW_{ac}).

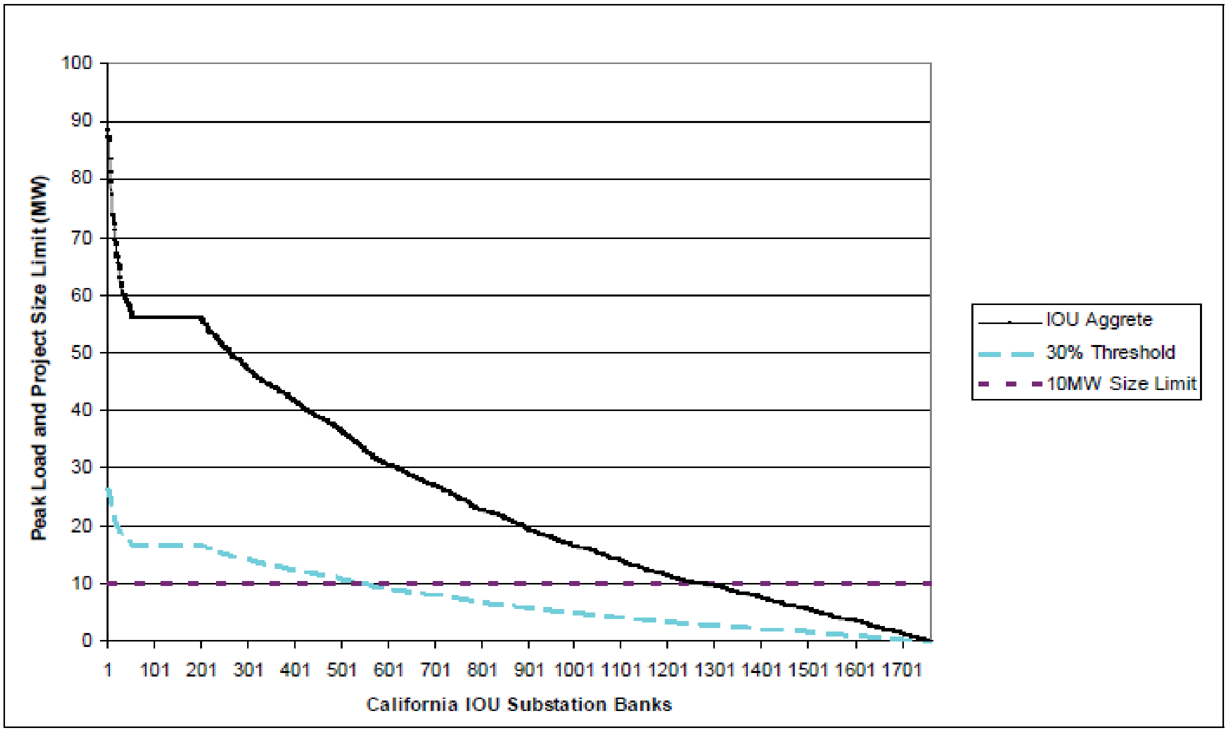
[17] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, p. 15.

day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential.

As a component of the DG FIT development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure 1. According to the CPUC, this data was obtained from IOU distribution engineers.[18] I calculate that approximately 13,300 MW of PV can be connected directly to IOU substation load banks based on the data in Figure 1. The supporting calculations for this estimate are provided in Table 2.

The IOUs provide about two-thirds of electric power supplied in California, with publicly-owned utilities like the Los Angeles Department of Water & Power and the Sacramento Municipal Utility District and others providing the rest.[19] Assuming the substation capacity pattern in Figure 1 is also representative of the non-IOU substations, the total California-wide PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Figure 1. IOU Substation peak loads, 30% of peak load, and 10 MW reference line



[18] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.

[19] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

Table 2. Calculation of distributed PV interconnection capacity to existing IOU substations with minimal interconnection cost from data in Figure 1

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

In sum, approximately 20,000 MW of distributed PV interconnection capacity is available now in California that would require little or no substation upgrading to accommodate the PV.

3. DG PV Is At Least as Cost-Effective as Solar Energy Production from HHSEGS

The CPUC prepares quarterly summary reports on the state's progress toward RPS goals. The fourth quarter 2011 report includes pricing data on RPS contracts for the first time, in conformance with SB 836 (2011) RPS contract price reporting requirements.[20] 2012 pricing data has not yet been published by the CPUC as of February 4, 2013. SB 836 requires that average RPS contract prices be reported by contract year, technology type, and size range by each IOU. The average 2010 and 2011 contract prices reported by PG&E for solar PV, solar thermal, and wind are summarized in Table 3.

Table 3. Average PG&E 2010/2011 RPS Contract Prices: PV, Solar Thermal & Wind[21]

Technology	Size range (MW)	2010 contract price ($/MWh)	2011 contact price ($/MWh)
PV	0 - 3	130	129
	3 - 20	167	114
	20 - 50	139	none listed
Solar thermal	50 - 200	144	none listed
Wind	20 - 200	126	118

Note: No explanation is provided in the CPUC 4th quarter 2011 report regarding why the 2010 PG&E 3-to-20 MW PV contract prices were nearly 30 percent higher than the 2010 contract prices for 0-to-3 MW PV systems.

Competitive 2011 power purchase contract prices for commercial rooftop PV systems in California are: $130/MWh for 1 MW systems, $140/MWh for 500 kW systems, and $150/MWh for 100 kW systems.[22] This pricing is consistent with the PG&E 2010 and 2011 average RPS contract prices of about $130/MWh for 0 to 3 MW PV systems. It is also consistent with the City

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[20] CPUC, *Renewable Portfolio Standard Quarterly Report – 4th Quarter 2011*, February 2012, Appendix A. See: http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf.

[21] Ibid, Appendix A, p. 4.

[22] Craig Lewis – Clean Coalition, *Making Clean Local Energy Accessible Now*, PowerPoint presentation, California Foundation for the Economy and Environment workshop on distributed renewable generation, Sausalito, California, December 8-9, 2011, p. 8.

of Palo Alto Utilities clean energy FIT program. The 2012 tariff price for commercial rooftop PV systems that are 100 kW or greater is $0.14/kWh, or $140/MWh.[23,24]

The 2011 contract price data reported by PG&E indicates that smaller scale PV systems, either 0-to-3 MW at $129/MWh or 3-to-20 MW at $114/MWh, are substantially more cost-effective than 50-to-200 MW solar thermal at $144/MWh.

4. There is Sufficient Existing Large Commercial Roof Space in PG&E and SCE Territories to Build at Least Sixteen HHSEGS Plants

The 2009 IEPR Final Committee Report recognizes the huge technical potential of rooftop distributed PV to meet California's renewable energy targets, stating:[25]

> Recent studies indicate substantial technical potential for distribution-level generation resources located at or near load. A 2007 estimate from the Energy Commission suggests that there is roof space for over 60,000 MW of PV capacity, although the study did not factor in roof space that is shaded or being used for another purpose.

60,000 MW is approximately the peak summertime load for all of California, and 120 times the 500 MW capacity of HHSEGS. It is important to note that the 2009 IEPR document is incorrect in asserting the 2007 rooftop PV estimate did not factor in roof shading or other limitations. The 60,000 MW estimate assumes only 24 percent of the rooftop of a typical tilt-roof residential rooftop is available for PV, and only 60 to 65 percent of flat-roof commercial rooftops are available for PV. The rationale for these estimates is explained in the 2007 (Navigant) estimate.[26]

The 60,000 MW rooftop PV estimate by Navigant does not account for any of the distributed PV described in the Renewable Energy Transmission Initiative (RETI) process. RETI was until recently California's most visible renewable energy transmission siting process. RETI evaluated a distributed PV alternative that would produce 27,500 MWac from 20 MW increments of ground-mounted PV arrays at 1,375 non-urban substations around the state.[27] Constructing distributed PV arrays around substations is the primary focus of PG&E's 500 MW distributed PV project.[28]

Black & Veatch is the engineering contractor preparing the RETI reports. Energy & Environmental Economics, Inc. (E3) is the engineering contractor that prepared the June 2009 CPUC preliminary analysis of the cost to reach 33 percent renewable energy by 2020. These two firms now lead the CPUC's renewable distributed generation ("Re-DEC") working group process. The presentation of E3 and Black & Veatch at the December 9, 2009 initial meeting of

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[23] See Palo Alto CLEAN Program webpage: http://www.cityofpaloalto.org/news/displaynews.asp?NewsID=1877&targetid=223.
[24] Greentech Media, *It's Official: Palo Alto, Calif. Has a Feed-In Tariff for PV*, March 6, 2012. See: http://www.greentechmedia.com/articles/read/Its-Official-Palo-Alto-Calif.-Has-a-Feed-In-Tariff-for-PV-/.
[25] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 193.
[26] See: http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF
[27] Renewable Energy Transmission Initiative, *RETI Phase 1B Final Report*, January 2009, p. 6-25.
[28] PG&E Application A.09-02-019, *Application of Pacific Gas and Electric Company to Implement Its Photovoltaic Program*, February 24, 2009.

the Re-DEC Working Group included an estimate of over 8,000 MW_{ac} of large commercial roof space in SCE and PG&E service territories in close proximity to existing distribution substations.[29]

Black & Veatch used GIS to identify large roofs in California and count available large roof area. The criteria used to select rooftops included:

- Urban areas with little available land
- Flat roofs larger than ~1/3 acre
- Assume 65 percent usable space on roof
- Within 3 miles of distribution substation

The Black & Veatch estimate for PG&E territory is 2,922 MWac. The estimate for SCE territory is 5,243 MWac. This is a combined rooftop PV capacity of over 8,000 MWac. The combined large commercial rooftop capacity is more than 16 times the 500 MW capacity of HHSEGS.

Large commercial rooftop PV capacity is a subset of the universe of all commercial rooftop capacity, which includes medium and small commercial rooftops as well. A 2004 Navigant study prepared for the Energy Foundation estimated the 2010 commercial rooftop PV capacity in California at approximately 37,000 MW_{dc}.[30] There is a tremendous amount of commercial roof space available for PV in California.

5. Slight Reduction in Output from Distributed PV in Los Angeles, Central Valley, or Bay Area Is Offset by Transmission Losses from HHSEGS to These Load Centers

The FSA implies that the superior solar intensity at the Hidden Hills location in the Mojave Desert is a substantive reason for eliminating distributed PV from consideration, stating (p. 6.1-4) that a project objective is to "Develop a renewable energy facility in an area with high solar value and minimal slope."

The solar insolation at the HHSEGS site is about 10 to 15 percent better than the composite solar insolation for Los Angeles, the Central Valley, and Oakland.[31,32] However, the CEC estimates average transmission losses in California at 7.5 percent and peak transmission losses at 14 percent.[33] The incrementally better solar insolation at the HHSEGS site is almost completely negated by the losses incurred by transmitting HHSEGS solar power to California urban areas. In contrast, distributed PV has minimal losses between generation and user.

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[29] E3 and Black & Veatch, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, presentation at Re-DEC Working Group Meeting, December 9, 2009, p. 24. Online at: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

[30] Navigant, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, prepared for The Energy Foundation, September 2004, p. 83. California commercial rooftop PV potential estimated at approximately 37,000 MWp.

[31] U.S. DOE, *Stand-Alone Flat-plate Photovoltaic Systems: System Sizing and Life-Cycle Costing Methodology for Federal Agencies*, 1984, Appendix, p. A-27.

[32] NREL, *Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors*, California cities data: http://rredc.nrel.gov/solar/pubs/redbook/PDFs/CA.PDF

[33] E-mail communication between Don Kondoleon, manager - CEC Transmission Evaluation Program, and Bill Powers of Powers Engineering, January 30, 2008.

6. CEC Has Already Determined Distributed PV Can Compete Cost-Effectively with Other Forms of Generation, Including Flexible Generation Gas Turbines

The CEC denied an application for a 100-megawatt natural-gas-fired gas turbine power plant, the Chula Vista Energy Upgrade Project (CVEUP), in June 2009 in part because rooftop solar PV could potentially achieve the same objectives for comparable cost.[34]

This June 2009 CEC decision implies that any future applications for gas-fired generation in California, or any other type of generation including remote central station renewable energy generation like GSEP that require public land and new transmission to reach demand centers, should be measured against using urban PV to meet the power need. The CEC's final decision in the CVEUP case stated:[35]

> Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.)….Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.)….PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted.

The CEC concluded in the CVEUP final decision that PV arrays on rooftops and over parking lots may be a viable alternative to the gas turbine project proposed in that case, and that if the gas turbine project proponent opted to file a new application a much more detailed analysis of the PV alternative would be required.

VI. There Is No Need for the Additional Flexible Capacity or for the CEC to Identify this as a Project Objective for HHSEGS

The FSA states (p. 6.1-3) that one project objective is to "develop a renewable energy facility capable of providing grid support by offering power generation that is flexible." The California grid has more than adequate existing sources of flexible generation to meet projected needs for the foreseeable future.[36] CAISO has been utilizing an erroneous 2020 solar profile graphic, and underestimating the flexibility of existing generation resources of all types, to assert that 1,000s of MW of new flexible generation is necessary by 2020. An accurate 2020 solar profile and reasonable assumptions about the flexibility of existing generation sources eliminate any need for flexibility to be a project objective for HHSEGS.

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[34] CEC, Chula Vista Energy Upgrade Project - Application for Certification (07-AFC-4) San Diego County, *Final Commission Decision*, June 2009.
[35] Ibid, pp. 29-30.
[36] Sierra Club and Vote Solar Intitiatve Comments on the Resource Adequacy and Flexible Capacity Procurement Joint Parties' Proposal, CPUC Rulemaking R.11-10-023, December 26, 2012.

VII. Distributed PV Provides Substantial Local Capacity to Urban Load Pockets, Offsetting the Need for Conventional Local Capacity, Remote Solar Like HHSEGS Does Not

Urban load pockets in California require a certain minimum amount of local generation to meet peak demand grid reliability requirements. The CPUC identifies the qualifying capacity for fixed and tracking solar PV systems, for grid reliability purposes, as 51 percent and 65 percent respectively.[37] Fixed or tracking PV systems located within urban load pockets provide a substantial amount of reliable local capacity. This local PV capacity offsets the justification to construct new conventional generation in the load pocket. Remote solar plants, like HHSEGS, provide no local qualifying capacity.[38]

VIII. Conclusion

The failure of the FSA to include a distributed PV alternative to HHSEGS is a fatal flaw in the alternatives analysis. The FSA should have concluded that distributed PV is a superior alternative to the HHSEGS.

[37] CPUC R.10-05-006, Planning Standards for Renewable Resources (last updated 2/2011), available at: http://docs.cpuc.ca.gov/efile/RULINGS/130670.pdf.

[38] B. Powers, *More Distributed Solar Means Fewer New Combustion Turbines*, Natural Gas & Electricity Journal, September 2012.

Declaration of Bill Powers, P.E.

Re: Testimony on Alternatives to the Application for Certification for the Proposed Hidden Hills Solar Electric Generating System Project

Docket 11-AFC-02

I, Bill Powers, declare as follows:

1) I am a self-employed consulting engineer.

2) My relevant professional qualifications and experience are set forth in the attached resume and the attached testimony and are incorporated herein by reference.

3) I prepared the testimony attached hereto and incorporated herein by reference, relating to the distributed PV alternative to the project and lack of support for generation flexibility as project objective.

4) I prepared the testimony attached hereto and incorporated herein by reference relating to the proposed Hidden Hills SEGS project.

5) It is my professional opinion that the attached testimony is true and accurate with respect to the issues that it addresses.

6) I am personally familiar with the facts and conclusions described within the attached testimony and if called as a witness, I could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: February 4, 2013 Signed: Bill Powers, P.E.

At: San Diego, California

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Twenty-five years of experience in:

- San Diego and Baja California regional energy planning
- Power plant technology, emissions, and cooling system assessments
- Combustion and emissions control equipment permitting, testing, monitoring
- Oil and gas technology assessment and emissions evaluation
- Latin America environmental project experience

SAN DIEGO AND BAJA CALIFORNIA REGIONAL ENERGY PLANNING

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. CHP systems would provide approximately 47 percent. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. This target is based on City of San Diego experience. San Diego has consistently achieved energy efficiency reductions of 20 percent on dozens of projects. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support.

Photovoltaic technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Photovoltaic arrays as alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Area Governments (SANDAG) Energy Working Group. Public interest representative on the SANDAG Energy Working Group (EWG). The EWG advises the Regional Planning Committee on issues related to the coordination and implementation of the Regional Energy Strategy 2030 adopted by the SANDAG Board of Directors in July 2003. The EWG consists of elected officials from the City of San Diego, County of San Diego and the four subareas of the region. In addition to elected officials, the EWG includes stakeholders representing business, energy, environment, economy, education, and consumer interests.

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

Imperial Valley Study Group. Participant in the Imperial Valley Study Group (IVSG), and effort funded by the CEC to examine transmission options for maximizing the development of geothermal resources in Imperial County. Advised the IVSG that no alternatives other than the Sunrise Powerlink or a similar variant were be considered to move Imperial Valley geothermal generation to San Diego. Initiated a dialogue on IVSG's failure to consider alternatives that was incorporated into the IVSG April 12, 2005 meeting minutes (see: http://www.energy.ca.gov/ivsg/documents/2005-04-12_meeting/2005-04-12_AMNDED_IVSG_MINUTES.PDF). Also co-authored with the Utility Consumers' Action Network an October 14, 2005 alternative letter report to the September 30, 2005 IVSG final report that documents numerous feasible transmission alternatives to the Sunrise Powerlink that were not considered by IVSG. The October 14, 2005 IVSG alternative letter report also served as a comment letter on the CEC's 2005 Integrated Energy Policy Report webpage is available at: http://www.energy.ca.gov/2005_energypolicy/documents/2005-10-11_DER_comments/10-14 05_Utility_Consumers_Action_Network_BPPWG.pdf

COMBUSTION AND EMISSIONS CONTROL EQUIPMENT PERMITTING, TESTING, MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author. Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California. Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California. Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County. Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District. Project manager and lead engineer for preparation of air permit application and BACT evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of BACT evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit. Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed Best Available Retrofit Control Technology (BARCT) emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

Ethanol Plant Dryer – Penn-Mar Ethanol, LLC. Lead engineer on BACT evaluation for ethanol dryer. Dryer nitrogen oxide (NO_x) emission limit of 30 ppm determined to be BACT following exhaustive review of existing and pending ethanol plant air permits and discussions with principal dryer vendors.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for a BARCT evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system and replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

POWER PLANT TECHNOLOGY, EMISSIONS, AND COOLING SYSTEM ASSESSMENTS

IGCC and Low Water Use Alternatives to Eight Pulverized Coal Fired 900 MW Boilers. Expert for cities of Houston and Dallas on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas. Also analyzed East Texas as candidate location for CO_2 sequestration due to presence of mature oilfield CO_2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Assessment of CO_2 Capture and Sequestration for IGCC Plants. Author of assessment prepared for a public interest client of CO_2 capture and sequestration options for IGCC plants. The assessment focuses on: 1) CO_2 sequestration performance of operational large-scale CO_2 sequestration projects, specifically the Weyburn CO_2 enhanced oil recovery (EOR) project, and 2) CO_2 EOR as the vehicle to offset the cost of CO_2 capture and serve as the platform for an initial set of U.S. IGCC plants equipped for full CO_2 capture and storage.

Assessment of IGCC Alternative to Proposed 250 MW Circulating Fluidized Bed (CFB) Unit. Lead engineer to evaluate IGCC option to proposed 250 MW CFB firing Powder River Basin coal. Project site is in Montana, where CO_2 EOR opportunities exist in the eastern part of the state.

500 MW Coal-Fired Plant –Air Cooling and IGCC. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^oF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Retrofit of SCR to Existing Natural Gas-Fired Units. Lead expert in successful representation of interests of the city of Carlsbad, California to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a 1,000 MW merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. Ultimately the plant owner was compelled to comply with the existing NO_x rule and install SCR on all five boilers at the plant. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Proposed 1.500 MW Pulverized Coal Power Plant. Provided testimony challenge to air permit issued for Peabody Coal Company's proposed 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that IGCC is a superior method for producing power from coal, from both environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost-competitive with pulverized coal.

Presidential Permits to Two Border Power Plants – Contested Air and Water Issues. Provided testimony on the air emissions and water consumption impact of two export power plants, Intergen and Sempra, in Mexicali, Mexico, and modifications necessary to minimize these impacts, including air emission offsets and incorporation of air cooling. These two plants are located within 3 miles of the California border, are interconnected only to the SDG&E transmission grid, and under the local control of the California Independent System Operator. Provided evidence that the CAISO had restricted the amount of power these two plants could export when commercial operation began in June 2003 to avoid unacceptable levels of transmission congestion on SDG&E's transmission system. The federal judge determined that the DOE had conducted an inadequate environmental assessment before issuing the Presidential Permits for these two plants and ordered the DOE to prepare a more comprehensive assessment.

300 MW Coal-Fired Circulating Fluidized Bed Boiler Plant - Best Available NO_x Control System. Provided testimony in dispute in case where approximately 50 percent NO_x control using selective non-catalytic reduction (SNCR) was accepted as BACT for a proposed 300 MW circulating fluidized bed (CFB) boiler plant in Kentucky. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that low-dust, hot side selective catalytic reduction (SCR) and tail-end SCR were technically feasible and could achieve greater than 90 percent NO_x reduction.

Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Prepared preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^oF and 13 ^oF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^oF and 13 ^oF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW

Roseton Generating Station in New York. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications. Closed-cycle cooling has been accepted as an issue that will be adjudicated.

2,000 MW Nuclear Power Plant – Closed-Cycle Cooling Retrofit Feasibility. Prepared assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station in New York. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Provided testimony in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant in Pennsylvania. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Emission Increases Associated with Retrofit of SCR Existing Coal-Fired Units. Provided testimony in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling. Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant in central coastal California. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^oF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

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W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

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P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* to be presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

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S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094